Novitas Energy Ltd

2003 ANNUAL REPORT

CORPORATE PROFILE

Novitas Energy Ltd. (TSX symbol – NOS) is a junior oil and gas producer that develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Company's business strategy is to strive to maximize shareholder value by applying long-term growth objectives. The Company's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our shareholders.

Contents

Notice of Annual General Meeting

The Annual General Meeting of Shareholders will be held on Wednesday, June 16, 2004, in the Lakeview Endrooms at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 10:00 a.m. (Calgary time).

Novitas
ENERGY LTD

HIGHLIGHTS	2003	2002
Financial ($000, except $ per share)		
Revenue - oil and gas (net of royalties)	5,565	3,977
Cash Flow from Operations [1]	3,350	2,092
Per Share Diluted	0.09	0.06
Net Income (Loss)	228	(24)
Per Share Diluted	0.01	(0.00)
Capital Expenditures and Acquisitions (net)	4,413	4,750
Outstanding Debt	4,793	5,227
Shareholders' Equity	5,393	5,150
Shares Outstanding (weighted average) (000's)	35,571	35,444
Operations		
Oil and Liquids (barrels per day)	553	421
Average Price ($ per barrel)	$31.84	$31.18
Natural Gas (MCF per day)	283	161
Average Price ($ per MCF)	$ 6.40	$ 3.90
Proven Plus Probable Reserves		
Oil and Liquids (barrels in 000's)	2,006	2,082
Natural Gas (MCF in 000's)	773	5,249

[1] Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other companies.

REPORT TO SHAREHOLDERS

It is with pleasure that we present to our shareholders the Company's operational and financial results for the year ending December 31, 2003. Novitas had a successful growth year in its second full year of operations, increasing production, cash flow and net income. During the year the Company was successful in defining the boundaries with a drill program to assist in determining future water flood programs in its prime producing area in the Shaunavon area of southwest Saskatchewan.

The Company was unsuccessful, however, in completing land acquisitions and farm-outs in the Peck Lake area of Saskatchewan during 2003 and therefore drilling has been delayed until the second quarter of 2004. Land issues were resolved in early 2004. The biggest disappointment in 2003 was the reduction in the Company's total reserves. This has been mainly attributable to a large adjustment to the natural gas reserves in the Sundance area of Alberta and in technical revisions to the Company's Peck Lake property.

Operations

The Company's gross crude oil proved reserves have been reduced from 2,008,000 barrels at December 31, 2002 to 1,773,000 barrels at December 31, 2003. Probable reserves during the comparable period increased by 159,000 barrels. The overall proved plus probable reduction for the year was from 2,082,000 barrels to 2,006,000 barrels, a reduction of 3.6 percent.

Natural gas reserves, however, had a major adjustment mainly due to a large write down for the Sundance area of west central Alberta and a reserve error adjustment from 2002 in the Peck Lake area. Proved natural gas reserves declined from 5,249 MMCF at December 31, 2002 to 706 MMCF at December 31, 2003. Reserves in 2003 for the Peck Lake area have been reduced to 658 MMCF of proven reserves from 2,688 MMCF due to an engineering calculation error in the January 1, 2003 reserve report. Probable reserves during the period increased by a modest 67 MMCF. On a reserve basis oil now accounts for 94 percent of total reserves.

Oil production increased from 421 barrels per day in 2002 to 553 barrels per day in 2003. Natural gas production increased to 283 MCF per day in 2003 from 161 MCF per day in 2002. The disappointing production volumes in the Sundance area and being unable to drill the Peck Lake prospect resulted in natural gas volumes being lower than expected in 2003.

Financial

Oil and natural gas revenue (net of royalties) increased to $5,565,000 in 2003 from $3,977,000 in 2002. Operating costs increased to $1,726,000 in 2003 from $1,403,000 in 2002 but declined on a barrel of oil equivalent bases (BOE), using a conversion of 6 MCF to 1 barrel, to $7.89 per BOE in 2003 from $8.58 per BOE in 2002.

Cash flow from operations increased to $3,350,000 from $2,092,000 in 2002. Net income for 2003 is $228,000 compared to a 2002 net loss of $24,000. There was little change in the price received for oil; $31.84 in 2003 and $31.18 in 2002.

Outlook

The Company will continue to grow by acquisitions of producing oil and gas properties, by optimizing production and reducing operating costs for acquired properties, and by drilling prospects that are developed internally or through farm-out arrangements with other companies. We anticipate that almost all of our activity will be in the Provinces of Alberta and Saskatchewan. The Company has also been active in acquiring interests in non-producing lands and will be drilling exploration prospects on these lands.

We wish to thank our shareholders for their continued support.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

REVIEW OF OPERATIONS

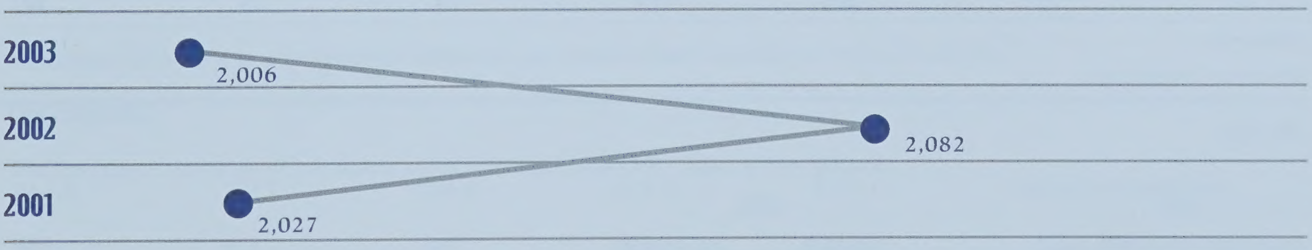
Reserves

The Company engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of January 1, 2004. The reserve valuation represents approximately 90 percent of the Company's property based on current production. Reserves relating to the balance of the Company's properties have not been evaluated and therefore have been excluded from the following tables. The reserves are located in the Provinces of Saskatchewan and Alberta. The majority of the Company's production is comprised of sweet 22 degree API crude. The Company's main oil producing area is located in the Shaunavon area of Saskatchewan. The gross figure in the following charts represents the Company's ownership interest before royalties and the net figure after royalties.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2003 (FORECAST PRICES AND COSTS)

	RESERVES			
	Light and Medium Oil		Natural Gas	
RESERVE CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
PROVED				
Developed Producing	1,773	1,541	48	44
Undeveloped	-	-	658	510
TOTAL PROVED	1,773	1,541	706	554
PROBABLE	233	196	67	61
TOTAL PROVED PLUS PROBABLE	2,006	1,737	773	615

OIL AND NGL RESERVES GROSS PROVEN AND PROBABLE (Mbbl's)



NATURAL GAS RESERVES GROSS PROVEN AND PROBABLE (mmcf)

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE (FORECAST PRICES AND COSTS)

	Light and Medium Oil			Natural Gas		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (mmcf)	Gross Probable (mmcf)	Gross Proved Plus Probable (mmcf)
December 31, 2002	2,008	74	2,082	5,249	-	5,249
Prior year reserves not evaluated	(49)	-	(49)	(242)	-	(242)
Discoveries	241	-	241	-	-	-
Technical revisions	(238)	159	(79)	(4,255)	67	(4,188)
Production	(189)	-	(189)	(46)	-	(46)
December 31, 2003	1,773	233	2,006	706	67	773

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS AT DECEMBER 31, 2003 (FORECAST PRICES AND COSTS)

NET PRESENT VALUE OF FUTURE NET REVENUE

After Income Taxes

Discounted at (%/year)

($000's) RESERVE CATEGORY	0	5	10	15	20
PROVED					
Developed Producing	14,617	10,934	8,863	7,527	6,594
Undeveloped	1,059	820	650	524	428
TOTAL PROVED	15,676	11,754	9,513	8,051	7,022
PROBABLE	1,894	975	600	417	315
TOTAL PROVED PLUS PROBABLE	17,570	12,729	10,113	8,468	7,337

Commodity prices used in the previous calculations of reserves are as follows:

Year	Hardisty Lloyd-Blend 22.3 API (Cdn $ per barrel)	Alberta Index Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2004	27.59	5.81	28.04	31.15	38.91
2005	24.34	5.15	22.56	25.52	35.07
2006	23.52	4.59	20.58	23.28	33.67
2007	24.07	4.71	20.89	23.63	34.17
2008	25.37	4.80	21.20	23.98	34.69
2009	25.85	4.88	21.52	24.34	35.21
2010	26.34	4.98	21.85	24.71	35.74
2011	26.83	5.05	22.18	25.08	36.28
2012	27.34	5.14	22.51	25.46	36.83
2013	27.85	5.24	22.85	25.85	37.38
2014	28.36	5.34	23.20	26.24	37.95
2015	28.89	5.43	23.55	26.63	38.52

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

Production

The following table provides a summary of average production volumes from our producing areas.

	2003		2002	
	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)
Shaunavon, Saskatchewan	518	-	383	-
Various non operated interests, Alberta	35	283	38	161
	553	283	421	161

Production of NGL's was less than two barrels per day and has been included in crude oil volumes.

Land Holdings

The Company's holdings of petroleum and natural gas leases and rights are as follows:

	2003		2002	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Saskatchewan	28,039	26,456	17,893	16,838
Alberta	5,440	833	7,080	1,352
	33,479	27,289	24,973	18,190

Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures incurred by the Company on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

	2003	2002
Property acquisition (see below)	$ 227,804	$3,172,696
Property dispositions	-	(401,718)
Drilling	3,873,262	2,921,417
Land costs	227,734	240,763
Seismic	70,639	99,571
Facility costs	-	120,700
Net petroleum and natural gas capital expenditures	$4,399,439	$6,153,423

In 2002 the Company acquired a private company at a cash cost of $1,964,000 (including 99,000 paid as a deposit in 2001). Due to accounting requirements, the property acquired through the acquisition of the private company was required to be recorded at an accounting cost of $3,272,000 with a future tax liability of $1,220,000.

Drilling History

The following tables summarize the Company's gross and net drilling activity and success:

	2003					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	7	6.51	-	-	7	6.51
Dry	3	2.94	-	-	3	2.94
Total	10	9.45	-	-	10	9.45
Success rate	70%	69%	-	-	70%	69%

	2002					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	3	2.84	-	-	3	2.84
Natural Gas	-	-	3	1.36	3	1.36
Dry	1	.93	1	1.00	2	1.93
Total	4	3.77	4	2.36	8	6.13
Success rate	75%	75%	75%	58%	75%	69%

No wells were drilled during the period June 15 to December 31, 2001

PROPERTY DISCUSSIONS

The Company's major producing properties are located in the Shaunavon area of southwest Saskatchewan. Novitas continues to acquire exploration lands in the west central area of Saskatchewan and has acquired exploration lands in the west central area of Alberta.

Southwest Saskatchewan

Novitas operates its' major producing property which consists of 53 producing wells in the Shaunavon area of southwest Saskatchewan where the Company's working interest averages approximately 94 percent. The properties are located in the Whitemud and Chambery fields and produce 22 degree API crude oil from the upper Shaunavon formation located at a depth of approximately 1,500 meters. A portion of the property is being produced under waterflood with the majority of the properties still on primary production. The primary production areas are being monitored on an ongoing basis to determine if water flood programs should be initiated. The wells in the Shaunavon area generally have a very long life and stable low decline production profile after a short period of higher decline when a new well initially commences production.

The Company conducted a development drilling program to determine pool boundaries that was successful in increasing production and reserves. The Company is taking the geological information learned from developing our existing land base and using it to locate other potential exploration prospects in the area.

Novitas will be testing a new geological shallow gas play after spring break-up. The play has the potential to add significant gas production and reserves from existing lands. Gas infrastructure within two kilometers of the Company's land may have a positive impact on economics and in the commencement of production.

Exploration Lands

Novitas has been working on developing a varied portfolio of exploration opportunities that could significantly increase production and reserves. The Company has acquired lower risk lands with multi-zone shallow gas potential in west central Saskatchewan and is also pursuing a shallow gas play in east central Alberta.

A successful 100 percent owned shallow gas well was drilled and completed in the Peck Lake area, west central Saskatchewan in 2002. Novitas has been attempting to and has finally been successful in completing its land base in the area. The Company plans further drilling in the area after spring break-up. Further drilling is required to justify the cost of the tie-in of the gas production from this remote area.

The Company was disappointed with the results from its deep gas tests in the Sundance area, west central Alberta. Both wells were successfully completed for gas production in secondary targets, however, production and reserves have been substantially lower than initially projected. The area is being re-evaluated prior to participating in any further development.

Novitas will be continuing to focus on acquiring, exploring, developing and producing new properties that have long term value.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This report dated March 31, 2004 is a review of the operations, current financial position and outlook for the Company and should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 2003, together with the notes related thereto.

Annual Comparisons	2003	2002	2001
Financial ($000, except $ per share)			
Revenue - oil and gas (net of royalties)	$ 5,565	$ 3,977	$ 531
Cash Flow from Operations [1]	3,350	2,092	66
Per Share Diluted	0.09	0.06	0.01
Net Income (Loss)	228	(24)	(92)
Per Share Diluted	0.01	(0.00)	(0.00)
Capital Expenditures and Acquisitions (net)	4,413	4,750	8,457
Total Assets	16,580	15,921	10,969
Outstanding Debt	4,793	5,227	3,146
Shareholders' Equity	5,393	5,150	5,020
Operations			
Oil and Liquids (barrels per day)	553	421	160
Natural Gas (MCF per day)	283	161	46

[1] Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other companies.

Quarterly Comparisons	2003			
	4th	3rd	2nd	1st
Financial ($000, except $ per share)				
Revenue - oil and gas (net of royalties)	$1,274	$1,358	$1,239	$1,694
Cash Flow from Operations	773	821	665	1,091
Per Share Diluted	0.02	0.02	0.02	0.03
Net Income (Loss)	(554)	349	143	290
Per Share Diluted	(0.01)	0.01	0.00	0.01
Capital Expenditures and Acquisitions (net)	1,654	1,093	704	962
Outstanding Debt	4,793	5,541	5,307	5,639
Shareholders' Equity	5,393	5,942	5,593	5,444
Operations				
Oil and Liquids (barrels per day)	557	563	525	566
Natural Gas (MCF per day)	249	300	372	211

	2002			
	4th	3rd	2nd	1st
Financial ($000, except $ per share)				
Revenue - oil and gas (net of royalties)	$1,212	$1,039	$ 898	$ 828
Cash Flow from Operations	633	594	456	409
Per Share Diluted	0.02	0.02	0.01	0.01
Net Income (Loss)	(249)	152	106	(33)
Per Share Diluted	(0.01)	0.01	0	(0)
Capital Expenditures and Acquisitions (net)	1,448	1,097	416	1,789
Outstanding Debt	5,227	4,742	4,647	4,704
Shareholders' Equity	5,150	5,386	5,233	5,127
Operations				
Oil and Liquids (barrels per day)	479	407	392	405
Natural Gas (MCF per day)	217	209	112	105

Production

The Company's average production of crude oil and natural gas liquids was 553 barrels per day in 2003 compared to 421 barrels per day in 2002. Natural gas production during 2003 averaged 283 MCF per day compared to 161 MCF per day in 2002. Total production in 2003 was lower than expected. The shortfall was due to lower production than expected from the development drilling completed in the Shaunavon area of southwest Saskatchewan, not being able to resolve land issues in the Peck Lake area of west central Saskatchewan that resulted in not being able to drill in 2003, and a much higher decline rate than anticipated from natural gas production in the Sundance area of west central Alberta.

OIL AND NGL PRODUCTION (Bbls/day)

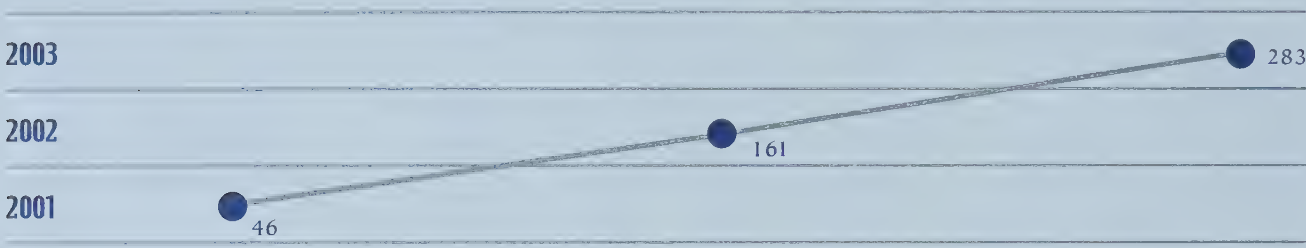
During 2003 the Company drilled 10 gross (9.45 net) wells. All of these wells were drilled in the Shaunavon area of Saskatchewan. Seven (6.51 net) were successful and were placed on production during the year. Three (2.94 net) were dry and abandoned. Production gains from these wells were lower than initially projected.

The Company successfully drilled an exploratory well in the Peck Lake area of west central Saskatchewan in 2002. In 2003 Novitas

focused on resolving land issues and satisfactorily resolved most of these during the first quarter of 2004. Further drilling in this highly prospective area will be completed in the second quarter of 2004.

Natural gas production at the Company's Sundance prospect has been disappointing. During the fourth quarter one of the wells was shut in due to pipeline problems. The well has subsequently been reactivated and current production is averaging less than 150 MCF per day from both wells. Due to the limited success, the Company's proven reserves on this prospect, as estimated as of December 31, 2002, have been reduced from 2.368 BCF to .048 BCF as of December 31, 2003.

NATURAL GAS PRODUCTION (MCF/day)

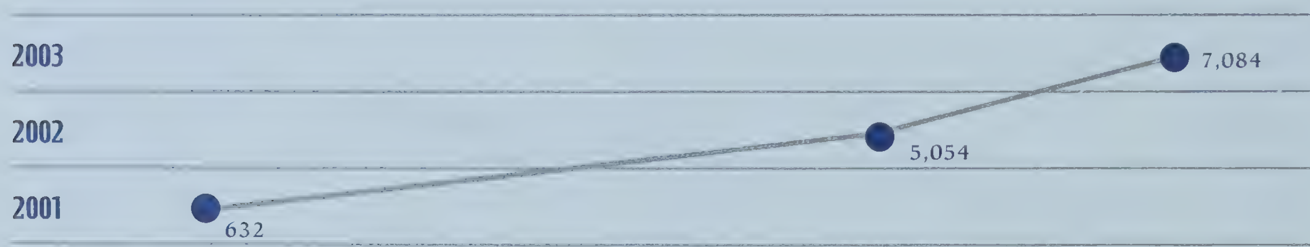


Revenue

Gross revenue from oil and natural gas sales increased to $7,083,501 in 2003 from $5,053,609 in the preceding fiscal year. The average price received for crude oil and natural gas liquids was $31.84 (2002 - $31.18) Cdn. per barrel and $6.40 (2002 - $3.90) Cdn. per MCF of natural gas. The Company did not enter into any commodity hedges during 2003.

Crude oil production consists primarily of 22 degree API crude oil that trades at a lower fluctuating differential to Edmonton par crude oil prices. Generally prices are higher during the summer months as there is increased demand for heavier crude oil for production of asphalt during the road construction and repair season.

GROSS REVENUES ($000)



Royalties

Royalties paid by the Company include both Crown royalties of $1,025,093 (2002 - $666,048) paid to the Provinces of Alberta and Saskatchewan and freehold and gross overriding royalties of $493,688 (2002 - $410,784). Newly drilled wells in Shaunavon are eligible for a Saskatchewan Crown royalty holiday. When the royalty holiday expires the higher producing wells have a royalty rate of approximately 20 percent.

Production Costs

Production costs totalled $1,726,419 in 2003 compared to $1,403,338 in 2002. On a barrel of oil equivalent (BOE) production costs averaged $7.89 (2002 - $8.58). BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation. The successful drilling of several high production rate wells in the Shaunavon area of Saskatchewan and upgrades to the Shaunavon facilities have resulted in lower production costs on a BOE basis in 2003. The Company anticipates that the development of its natural gas play in the second quarter of 2004 should further reduce the operating costs on a per unit-of-production basis.

PRODUCTION COSTS ($ per BOE)

General and Administrative Expense

General and administrative expenses were $204,747 or $0.71 per BOE compared to $253,493 or $1.55 per BOE in 2002. General and administrative costs consist primarily of management fee expenses (see below), engineering report fees, annual report costs, and audit fees.

The Company has a management agreement with Comstate Resources Ltd. (Comstate) a wholly owned subsidiary of Bonterra Energy Income Trust (an entity with similar directors and management). During 2003, the Company paid a management fee to Comstate for management services of $10,000 (2002 - $5,000) per month plus five percent of before tax income. The increase in the management fee was offset by a reduction in operational salaries. The management agreement can be cancelled by either party giving 30 days notice.

General and administrative expenses in the fourth quarter declined from those reported in the third quarter due mainly to a reduction in the management fee of $42,300. The adjustment was due to fees being charged on lower net earnings before tax numbers. The lower net earnings were due to an increase in the Company's depletion provision because of the reserve revisions. Please see discussion under Depletion, Depreciation, Future Site Restoration and Dry Holes.

GENERAL AND ADMINISTRATIVE ($ per BOE)

Interest Expense

Interest expense for 2003 was $273,747 compared to $208,509 for the preceding fiscal year. The increase was due to an increase in the average outstanding loan amount to $5,570,000 in 2003 from $4,830,000 in 2002 plus an increase in the average interest rate charged by the Company's banker on the outstanding debt from 4.3 percent in 2002 to 4.9 percent in 2003. The Company has the ability to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one third percent lower than that charged on the general loan account.

Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

The Company follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Company depletes its oil and natural gas intangible assets using the unit-of-production basis by field. The Company believes that the successful efforts method of accounting provides a more accurate cost of the producing properties than the alternative measure of full cost accounting.

For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one-tenth of original cost per year. The use of a ten year life span instead of calculating depreciation over the life of reserves was determined to be more representative of actual costs of tangible property. The Company's long production life wells generally require replacement of tangible assets more than once during their lifetime.

A provision is made for abandonment and future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit-of-production basis by field. Effective January 1, 2004, the Company is required to change how it reports its future site restoration. Under the new accounting rules a discounted estimate of the total abandonment and site reclamation costs using escalating cost assumptions is required to be recorded with an offset to the cost of the related intangible assets. The adjustment to the intangible assets will be depleted as per the above discussion. The change will be retroactively applied with restatement. The impact of this adjustment on the Company's 2003 and prior year's results will be reported in the Company's first quarter report as follows:

	Increase (Decrease)
Opening deficit (Jan 2003)	$ (32,753)
Fixed Assets	1,047,057
Accumulated depletion	202,306
Future site restoration	821,175
Depletion, depreciation and future site restoration	(45,267)
Accretion expense	54,444

The calculation of the above requires an estimation of the amount of the Company's petroleum reserves by field. This figure is calculated annually by an independent engineering firm and any adjustments are used to recalculate depletion and future site restoration. This calculation is to a large extent subjective. The extent of reserves is affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased depletion costs will vary. New rules for determining reserves, effective for 2003, may however provide a level of consistency that may assist in reducing the extent of revisions that have plagued the resource industry in the past.

For the fiscal year ending December 31, 2003, the Company expensed $2,588,127 (2002 - $1,500,171) for the above-described items.

The Company is required to examine by area the net asset value it has recorded on properties compared to their estimated future value. Given the adjustment in reserves as discussed under Production, the Company wrote down its net asset value in the Sundance property by $485,027. This amount has been included in the Company's depletion, depreciation and future site restoration expense.

As mentioned above, Novitas follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. During 2003, the Company drilled three gross (2.94 net) wells that were dry and abandoned. Total expenses including land and seismic costs associated with these wells were $669,677 (2002 - $389,573).

Income Taxes

Tax expense consists entirely of federal and provincial large corporation capital tax. The Company currently has sufficient tax pools to eliminate taxable income. It is however estimated that the Company will incur federal and provincial income tax in 2004.

The Company has adopted the tax payable method of accounting for income taxes under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary difference will reverse. The liability on the balance sheet and the corresponding expense relates to temporary differences existing between the Company's book value of its assets and its remaining tax pools. The Company received tax pools significantly less than the acquisition costs for the companies it has acquired, and as such had to record a sizable future income tax liability.

Tax pool balances at the end of 2003 totalled $7,166,807 and consisted of the following pool balances:

	Rate of Utilization %	
Undepreciated capital costs	25-30	$1,646,656
Canadian oil and gas property expenses	10	2,818,999
Canadian development expenses	30	2,142,299
Canadian exploration expenses	100	500,438
Finance expenses	20	58,415
		$7,166,807

Net Income (Loss)

Novitas had net income of $227,966 in 2003 compared to a $23,966 net loss in the previous fiscal year. The 2003 net income was significantly reduced primarily due to dry hole costs of $669,677 and increased depletion, due to reserve adjustments, of approximately $1,500,000 (including a write down of net assets of $485,027) offset partially by a recovery of future income taxes of $620,526.

The Company's use of the successful efforts method of accounting for its oil and gas assets lends itself to increased volatility in

the determination of net income as costs associated with unsuccessful wells are written off immediately instead of being capitalized and amortized over the life of other productive assets.

NET INCOME (LOSS) ($000)

Cash Flow from Operations

Cash flow from operations for the year ending December 31, 2003 was $3,350,271 (2002 - $2,092,309). Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other companies. Increased cash flow was due to several factors including higher commodity prices and increased production levels. As with all oil and gas producers the Company's cash flow is highly dependent on commodity prices. International events and control of crude oil production by OPEC and a potential shortage of natural gas in North America are likely factors that will result in 2004 commodity prices being high and having a positive impact on cash flow.

Cash Netback

The following table illustrates the Company's cash netback:

$ per BOE	2003	2002
Production volumes (BOE)	218,859	163,509
Gross production revenue	$32.37	$30.72
Royalties	(6.93)	(6.59)
Field operating	(7.89)	(8.58)
Field netback	17.55	15.55
General and administrative	(0.71)	(1.55)
Interest and taxes	(1.30)	(1.44)
Cash netback	$15.54	$12.56

Liquidity and Capital Resources

At December 31, 2003 the Company had bank debt of $4,793,438 (December 31, 2002 - $5,227,328). The Company has a $6,000,000 revolving credit facility reducing by $100,000 per month commencing January 31, 2004 and carries an interest rate of one percent above Canadian chartered bank prime. The terms of the credit facility provide that the loan is due on demand and

subject to review on March 31, 2004. The credit facility can be drawn on by way of a bank prime rate loan, banker acceptances (BA's), letters of credit and letters of guarantee.

As mentioned above, the credit facility allows for borrowings by means of BA's. The effective interest rates of BA's are generally a third percentage point lower than that available under the normal credit facility. The Company attempts to maximize the amount of its credit facility used by financing with BA's to reduce overall interest costs. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets, and a general securities agreement. During 2003 the Company amended its credit facility so that Comstate no longer has to provide a guarantee.

The Company has no contractual obligations that last longer than 12 months.

The Company is authorized to issue an unlimited number of common shares without nominal or par value. The following table outlines changes to the Company's outstanding shares over the past two years:

	2003		2002	
	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of year	35,516,234	$5,265,957	35,426,234	$5,252,457
Issued pursuant to Company stock option plan	102,000	15,300	90,000	13,500
Balance, end of year	35,618,234	$5,281,257	35,516,234	$5,265,957

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,550,000 shares of common stock. The exercise price of each option granted equals the market price of the Company's stock on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Company's stock option plan as of December 31, 2003 and 2002, and changes during the years ending on those dates is presented below:

	2003		2002	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	2,179,000	$0.17	2,274,000	$0.15
Options granted	442,000	0.93	135,000	0.55
Options exercised	(102,000)	0.15	(90,000)	0.15
Options cancelled	(76,000)	0.15	(140,000)	0.15
Outstanding at end of year	2,443,000	$0.31	2,179,000	$0.17
Options exercisable at end of year	1,261,000	$0.16	668,000	$0.15

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/03	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/03	Weighted-Average Exercise Price
$0.15	1,866,000	2.8 years	$0.15	1,216,000	$0.15
$0.55-$0.65	195,000	2.1 years	$0.58	45,000	$0.55
$0.97	382,000	3.3 years	$0.97	-	-
$0.15 - $0.97	2,443,000	2.8 years	$0.17	1,261,000	$0.16

The Company accounts for its stock based compensation plan using intrinsic values. Under this method no costs are recognized in the financial statements for share options granted to employees and directors when the options are issued at prevailing market prices. For fiscal years beginning on or after January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net income using the fair market value method for stock options issued on or after January 1, 2002. If the fair value method had been used, the Company's 2003 net income would be reduced by $65,120 (2002 - $22,937 increase loss) and net income (loss) per share would not be significantly different from those reported. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted average risk free interest rate of 3.75 (2002 - 5.2) percent, expected weighted average volatility of 106 (2002 - 114) percent, and expected weighted average life of 3.6 (2002 - 3.75) years.

Effective January 1, 2004, the Company will be required to report all stock options using the fair value method. The Company will retroactively restate its financial information back to 2002. The impact to the December 31, 2003 financial information (including adjustments for 2002) is as follows:

	Increase (Decrease)
Opening deficit	$22,937
Contributed surplus	85,057
General and administrative expense (2003)	62,120

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Company's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Company presently attempts to minimize these risks by pursuing both oil and natural gas activities. The Company may sometimes elect to protect against price fluctuation by using commodity hedging. Currently the Company has no outstanding hedging agreements.

The Company operates its oil and natural gas interests in areas which have long life reserves; where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

Sensitivity Analysis

Sensitivity analysis, as estimated for 2003 follow:

	Cash Flow	Cash Flow Per Share
U.S. $1.00 per barrel	$149,000	$0.004
Canadian $0.10 per MCF	$ 14,000	$0.001
Change of Canadian $0.01/U.S. $ exchange rate	$ 57,000	$0.002

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
President and CEO

Garth E. Schultz
Vice President, Finance and CFO

AUDITORS' REPORT

To the Shareholders of Novitas Energy Ltd.:

We have audited the balance sheets of **Novitas Energy Ltd.** as at December 31, 2003 and 2002 and the statements of income and retained earnings and of cash flow for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as, evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta

March 26, 2004

BALANCE SHEETS

As at December 31	2003	2002
Assets		
Current		
Accounts receivable	$ 920,835	$ 881,947
Prepaid expenses	42,816	21,911
	963,651	903,858
Property and Equipment *(Note 2)*		
Property and equipment	20,266,428	16,524,476
Accumulated depletion and depreciation	(4,438,450)	(1,507,736)
Net property and equipment	15,827,978	15,016,740
	$16,791,629	$15,920,598
Liabilities		
Current		
Bank indebtedness	$ 1,028,768	$ 482,363
Accounts payable and accrued liabilities	2,016,507	1,021,522
Bank loan *(Note 3)*	4,793,438	5,227,328
	7,838,713	6,731,213
Future income tax liability *(Note 6)*	3,239,535	3,860,061
Future site restoration	320,500	179,709
	11,398,748	10,770,983
Shareholders' Equity		
Share capital *(Note 4)*	5,281,257	5,265,957
Retained earnings (deficit)	111,624	(116,342)
	5,392,881	5,149,615
	$16,791,629	$15,920,598

On behalf of the Board:

George F. Fink
Director

F. William Woodward
Director

STATEMENTS OF INCOME AND RETAINED EARNINGS

Years ended December 31	2003	2002
Revenue		
Oil and gas sales, net of royalties of $1,518,781		
(2002 - $1,076,832)	$5,564,720	$3,976,777
Production costs	(1,726,419)	(1,403,338)
Interest and other	562	8,198
	3,838,863	2,581,637
Expenses		
General and administrative	204,747	253,493
Interest on long-term debt	273,747	208,509
	478,494	462,002
Cash Flow From Operations Before		
Current Income Taxes	3,360,369	2,119,635
Loss on disposal of oil and gas property *(Note 2)*	-	32,676
Dry hole costs	669,677	389,573
Depletion, depreciation and future site restoration	3,073,154	1,500,171
Income (Loss) Before Income Taxes	(382,462)	197,215
Income Taxes (Recovery) *(Note 6)*		
Current	10,098	27,326
Future	(620,526)	193,855
	(610,428)	221,181
Net Income (Loss) For The Year	$ 227,966	$ (23,966)
Deficit, Beginning of Year	(116,342)	(92,376)
Retained Earnings (Deficit), End of Year	$ 111,624	$(116,342)
Income (Loss) Per Share Basic and Diluted *(Note 1)*	$ 0.01	$ (0.00)

STATEMENTS OF CASH FLOW

Years ended December 31	2003	2002
Operating Activities		
Net income (loss) for the year	$ 227,966	$ (23,966)
Items not affecting cash		
Loss on disposal of oil and gas property (Note 2)	-	32,676
Dry hole costs	669,677	389,573
Depletion, depreciation and future site restoration	3,073,154	1,500,171
Future income taxes	(620,526)	193,855
Cash Flow From Operations	3,350,271	2,092,309
Change in non-cash operating working capital		
Accounts receivable	(38,888)	(495,320)
Prepaid expenses	(20,905)	(13,851)
Accounts payable and accrued liabilities	994,986	624,712
	935,193	115,521
	4,285,464	2,207,850
Financing Activities		
Increase (decrease) in bank loan	(433,890)	2,081,674
Issue of common shares for cash	15,300	13,500
	(418,590)	2,095,174
Investing Activities		
Property and equipment expenditures (Note 2)	(4,413,279)	(5,369,576)
Cash acquired on acquisition	-	504
Proceeds on disposal of property and equipment (Note 2)	-	619,923
	(4,413,279)	(4,749,149)
Net Cash Outflow	(546,405)	(446,125)
Bank Indebtedness, Beginning of Year	(482,363)	(36,238)
Bank Indebtedness, End of Year	$(1,028,768)	$ (482,363)

Cash interest and taxes paid (See Notes 3 and 6)

NOTES TO THE FINANCIAL STATEMENTS

Years ended December 31, 2003 and 2002

1. SIGNIFICANT ACCOUNTING POLICIES

Measurement Uncertainty

The amounts recorded for depreciation and depletion of petroleum and natural gas property and equipment and for future site restoration and reclamation are based on estimates of petroleum and natural gas reserves and future costs. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Petroleum and Natural Gas Properties and Related Equipment

The Company follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized. When property is found to contain proved reserves as determined by Company engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proved reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Income Taxes

The Company follows the liability method of accounting for income taxes under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary differences will reverse.

Future Site Restoration

The Company provides for abandonment costs and future site restoration over the estimated production life of its property and equipment. Estimates of these amounts are based on the anticipated method and extent of site restoration using current costs and in accordance with existing legislation and industry practice. The annual charge calculated on a unit-of-production basis is included with depletion, depreciation and future site restoration.

Stock-based Compensation Plan

The Company has a stock-based compensation plan, which is described in Note 4. No compensation expense is recognized for these plans when stock options are issued at the prevailing market prices. Any consideration paid by employees or directors on the exercise of these options is recorded as share capital. For options issued after January 1, 2002, the fair values are determined and the impact on earnings is disclosed as pro forma information.

Revenue Recognition

Petroleum and natural gas sales are recognized when the commodities are delivered to purchasers.

Hedging

The Company uses derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Gains and losses on these contracts, all of which constitute effective hedges, are recognized as a component of oil and gas sales.

Joint Interest Operations

Significant portions of the Company's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Net Income (Loss) Per Common Share

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options or warrants to purchase common shares were exercised. The treasury stock method is used to determine the dilutive effect of stock options and warrants, whereby proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the year.

The number of shares used to calculate diluted net income (loss) per share for the year ended December 31, 2003 of 37,198,999 (2002-37,019,220) included the weighted average number of shares outstanding of 35,571,401 (2002-35,443,734) plus 1,627,598 (2002-1,575,486) shares related to the dilutive effect of stock options.

2. PROPERTY AND EQUIPMENT

	2003		2002	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Petroleum and natural gas properties and related equipment	$20,266,428	$4,438,450	$16,524,476	$ 1,507,736

On January 3, 2002, the Company acquired 100 percent of the outstanding shares of a private company for a cash payment of $1,925,100. The determination of the purchase price of the acquisition and allocations to the net assets and liabilities of the acquired company based upon the fair value of the assets acquired and liabilities assumed was as follows:

Cash Consideration	$1,925,100
Related Expenses and Fees	38,518
Total Purchase Price	$1,963,618
Purchase Price Allocation	
Net Working Capital	$ 98,434
Capital Assets	3,271,928
Long-term Debt	(186,281)
Future Income Taxes	(1,220,463)
Total Purchase Price	$1,963,618

Effective February 1, 2002, the Company sold to Bonterra Energy Income Trust (Bonterra) the petroleum and natural gas property it purchased from Bonterra for its initial public offering. The property was no longer considered to be significant and was not in an area that the Company was considering for future growth. Total consideration paid was $575,000 cash. The Company recorded the sale as a reversal of the original purchase and reported a loss on disposal of $32,676.

Included in the depletion, depreciation and future site restoration provision of $3,073,154 is an asset write-down of $485,027 relating to an exploration play in west central Alberta. Although the Company has two producing wells, the evaluated reserves based on third party engineering do not support the costs incurred to develop the property.

No general and administrative expenses were capitalized during the years ended December 31, 2003 or 2002.

At December 31, 2003, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are $1,854,187 (2002 - $1,882,187).

3. BANK LOAN

The Company has a long-term revolving credit facility of $6,000,000 as of December 31, 2003. As at December 31, 2003 the Company had drawn under the facility $4,793,438 (2002 - $5,227,328). The terms of the credit facility provide that a reduction of $100,000 in the total amount of the facility is required at the end of each month commencing on January 31, 2004, the loan is due on demand and is subject to annual review. The credit facility can be drawn by way of bank prime rate loan, banker acceptances (BA's), letters of credit and letters of guarantee.

The interest rate on the prime rate loan is the bank's prime rate plus one percent. The interest rate on BA's is the bank's BA rate plus 2.25 percent. The letters of credit and guarantee are issued for a fee determined by the bank at the date of issue. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets, and a general securities agreement. As a result of the amended credit facility Comstate Resources Ltd. (Comstate), the management company, no longer is required to provide a $3,000,000 guarantee.

The Company has classified borrowing under its bank facility as a current liability as required by guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans, which are required to be classified as a current liability, are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with.

Cash interest paid in the year for the above loan was $261,555 (2002 - $208,509).

4. SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

Iuused	2003		2002	
	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of year	35,516,234	$5,265,957	35,426,234	$5,252,457
Issued pursuant to Company stock option plan	102,000	15,300	90,000	13,500
Balance, end of year	35,618,234	$5,281,257	35,516,234	$5,265,957

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,550,000 shares of common stock. The exercise price of each option granted equals the market price of the Company's stock on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Company's stock option plan as of December 31, 2003 and 2002, and changes during the years ending on those dates is presented below:

	2003		2002	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	2,179,000	$0.17	2,274,000	$0.15
Options granted	442,000	0.93	135,000	0.55
Options exercised	(102,000)	0.15	(90,000)	0.15
Options cancelled	(76,000)	0.15	(140,000)	0.15
Outstanding at end of year	2,443,000	$0.31	2,179,000	$0.17
Options exercisable at end of year	1,261,000	$0.16	668,000	$0.15

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/03	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/03	Weighted-Average Exercise Price
$0.15	1,866,000	2.8 years	$0.15	1,216,000	$0.15
$0.55-$0.65	195,000	2.1 years	$0.58	45,000	$0.55
$0.97	382,000	3.3 years	$0.97	-	-
$0.15 - $0.97	2,443,000	2.8 years	$0.17	1,261,000	$0.16

The Company accounts for its stock based compensation plan using intrinsic values. Under this method no costs are recognized in the financial statements for share options granted to employees and directors when the options are issued at prevailing market prices. For fiscal years beginning on or after January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net income using the fair market value method for stock options issued on or after January 1, 2002. If the fair value method had been used, the Company's 2003 net income would be reduced by $65,120 (2002 - $22,937 increase loss) and net income (loss) per share would not be significantly different from those reported. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted average risk free interest rate of 3.75 (2002 - 5.2) percent, expected weighted average volatility of 106 (2002 - 114) percent, and expected weighted average life of 3.6 (2002 - 3.75) years.

5. MANAGEMENT AGREEMENT

During 2003, the Company paid a management fee to Comstate for management services of $10,000 per month (2002 - $5,000) plus five percent of before tax income. Total payments made during 2003 were $120,000 (2002-$73,300) and have been included in general and administrative expenses.

The Company also paid administrative fees on a per well basis to Comstate for the administration of its oil and gas properties. Total amount paid during 2003 was $148,000 (2002-$128,500). This amount, net of amounts related to joint venture partner interests, has been recorded in production costs.

6. INCOME TAXES

The Company has recorded a future income tax liability. The liability relates to the following temporary differences:

	2003 Amount	2002 Amount
Temporary differences related to assets and liabilities	$3,266,804	$3,896,663
Other	(27,269)	(36,602)
	$3,239,535	$3,860,061

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	2003 Amount	2002 Amount
Income (loss) before income taxes	$(382,462)	$197,215
Combined federal and provincial income tax rates	40.56%	45.44%
Income tax provision calculated using statutory tax rates	(155,127)	89,614
Increase (decrease) in income taxes resulting from:		
Non-deductible crown royalties	384,036	316,187
Resource allowance	(432,569)	(342,568)
Tax rate adjustment	(384,591)	142,068
Other	(32,275)	(11,446)
Capital taxes	10,098	27,326
	$(610,428)	$221,181

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	25-30	$1,646,656
Canadian oil and gas property expenses	10	2,818,999
Canadian development expenses	30	2,142,299
Canadian exploration expenses	100	500,438
Finance expenses	20	58,415
		$7,166,807

Cash taxes paid in 2003 were $33,805 (2002 - Nil).

7. FINANCIAL INSTRUMENTS

Fair Values

The Company's financial instruments included in the balance sheet are comprised of accounts receivable and current liabilities, including the revolving demand loan. The fair values of these financial instruments approximate their carrying value due to the short-term maturity of those instruments. Borrowings under bank credit facilities are market based, thus, carrying values approximate fair value.

Credit Risk

Substantially all of the Company's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of associated credit risks.

Interest Rate Risk

The Company's bank debt is comprised of a revolving loan with a floating interest rate and as such the Company is exposed to interest rate risk.

Commodity Price Risk

The nature of the Company's operations results in exposure to fluctuations in commodity prices and exchange rates. The Company monitors and when appropriate uses derivative financial instruments to manage its exposure to these risks.

CORPORATE INFORMATION

Board of Directors

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F. W. Woodward, Calgary, Alberta

Officers

G.F. Fink – President and CEO

R.M. Jarock – Vice President Corporate Development and Operations Manager

G.E. Schultz – Vice President Finance and Secretary

Registrar & Transfer Agent

Olympia Trust Company, Calgary, Alberta

Auditors

Deloitte & Touche LLP, Calgary, Alberta

Solicitors

Parlee McLaws, Calgary, Alberta

Tupper, Jonsson & Yeadon, Vancouver, British Columbia

Bankers

The Royal Bank of Canada, Calgary, Alberta

Stock Listing

TSX Venture Exchange

Trading symbol: NOS

Website

www.novitasenergy.com

Head Office

901, 1015 – 4th Street SW, Calgary, Alberta T2R 1J4

PH 403.262.1400 FX 403.265.7488

Novitas
ENERGY LTD

901, 1015 – 4th Street SW, Calgary, Alberta T2R 1J4 PH 403.262.1400 FX 403.265.7488 www.novitasenergy.com